LTC/jva 11/13/2002

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking on policies and Practices for advanced metering, demand Response, and dynamic pricing. | Rulemaking 02-06-001 |

# ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING FOLLOWING THE THIRD MEETING OF WORKING GROUP 1

## I. Summary

This ruling addresses certain developments that have occurred since the October 15, 2002 Working Group (WG) 1 meeting, and anticipates a fourth meeting of WG 1 which is scheduled for December 4, 2002. Since the last WG 1 meeting, WGs 2 and 3 have continued to make progress, and staff facilitating or monitoring these groups have kept WG1 representatives fully informed of that progress. In addition, on October 25, 2002, the CPUC issued a decision in the procurement rulemaking (R.01-10-024) that included reference to specific demand response issues under consideration in this proceeding and required the utilities to include demand response in their procurement planning processes. Finally, on October 29, 2002, ALJ Carew issued a ruling requesting parties' comments on the most recent draft vision statement. We will review these comments and further refine the vision statement before December 4th.

Given these developments, we believe it is time for WG 1 to provide more definitive guidance to WGs 2 and 3 as they continue meeting and preparing the reports that will inform the Phase 1 decision in this rulemaking. Because the issues addressed in this ruling are primarily focused on further defining the scope of our work, we do not solicit further comment at this time, except for the issues related to utility procurement plans, where comments are due on November 26th. We do, however, request that respondents and parties come prepared to address certain issues at the next WG 1 meeting, as discussed in further detail below.

## II. Outstanding Implementation Issues

### A. Cost Effectiveness

In the October 2, 2002 Ruling Following the Second Meeting of Working Group 1, we asked parties to comment on a number of potential inputs to cost-effectiveness calculations to value peak demand reductions. Taking into account the numerous comments received on this issue, we present in the following table two alternatives for use in valuing peak load reduction realized through programs or tariffs. Even for pilot programs, decisionmakers need an understanding of likely costs and benefits, though the analysis may be less rigorous than for full-scale programs or tariffs. Though we expect cost-effectiveness analysis for all pilot programs and tariffs, we do not plan to impose any minimum benefit-cost ratios for consideration. It is entirely possible that benefits may not exceed costs for pilot efforts. At this point, the purpose of the cost-effectiveness analysis is simply informational and may also help us distinguish between various proposals.

The alternatives for cost-effectiveness inputs given below were selected to represent the range of most likely resources for which demand reductions would substitute in the current power resource market.

Alternative 1: A newly constructed peaker plant; simple cycle technology with a heat rate of 10,000 btu / hour.

Alternative 2: An existing, older peaker plant with a heat rate of 20,000 btu / hour.

| | Fixed Costs | Fixed+ (per MWh) fuel costs* | | |
|---|---|---|---|---|
| ALTERNATIVE | $/kW-yr | 50 hr | 100 hr | 200 hr |
| New Simple Cycle Gas Turbine (10,000 btu/hr) | $85 | $1,735 | $885 | $460 |
| Existing Generation (20,000 btu/hr) | $10 | $270 | $170 | $120 |

* Assumes $3.5/Mmbtu gas

These values only quantify the direct financial avoided costs of load reductions as an input to a complete cost-benefit analysis. A complete analysis should include environmental value (criteria pollutant emissions and air quality impacts, land/water use impacts, greenhouse emissions, etc.), insurance/reliability value, market effects, fuel price stability and other criteria that are more difficult to quantify. The values above provide a starting point for cost-effectiveness analysis by the working groups, while these additional factors are more fully developed.

For purposes of analysis in Phase 1 of this proceeding, WGs 2 and 3 must use these values in conducting cost-effectiveness assessments. WGs 2 and 3 may also include additional values if they believe other sensitivities are warranted.

### B. The Two-Part Tariff

The October 2nd Ruling proposed a definition of a two-part tariff and requested comment on the potential use of this concept by the Working Groups, especially WG 2. Several parties addressed the issue in their comments and during the October 15th WG 1 meeting. Both San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (Edison) highlight the problem of assigning reasonable customer baselines (CBLs), SDG&E stating that customers should be required to accumulate 12 months of interval data before being allowed to participate (WS-3 RT 258:12-23; 263:1-12). The Office of Ratepayer Advocates also notes that the establishment of baseline amounts is a definite implementation difficulty, although not an insurmountable obstacle.[1] The utilities also have concerns about revenue neutrality if additional investment in transmission and distribution facilities is required to meet changing on- or off-peak demand levels (WS-3 RT 258:24 – 259:7). Finally current surcharge levels are very large, and customers may not accept two-part real time tariffs that build on this baseline (WS-3 RT259: 8-20).

Given these implementation issues, it is clear that there is insufficient time remaining before the WG 2 report is due to analyze the pros and cons of the two-part tariff and to develop a complete proposal. We do, however, wish to consider the merits of a two-part tariff more fully in the future, and entertain the option of offering such a tariff to customers. Thus, as part of its report, we expect WG 2 to include a schedule for full analysis, development and implementation of a two-part tariff during the next phase of this proceeding.

### C. Cost Recovery Issues

During the October 15th WG 1 meeting, the staff presented an overview of cost recovery issues,[2] and we provided each respondent an opportunity to address the issue on the record. Respondents believe that WG 1 must address the issue of timely recovery of costs associated with both pilot and wider scale dynamic pricing and demand response programs, especially because utilities must be assured that cost recovery systems are in place that accommodate the

[1] ORA's Comments to the October 2nd Ruling, pp. 2-3

[2] The document presented by WG 1 staff entitled "Summary of Cost Recovery Issues" is attached to this ruling as Item 1.

necessary lead times for meter ordering and beginning billing system changes. (WS-3 RT 263:8-12; 265:22 – 266:3.)

There was much discussion of the need to have these metering and billing systems in place in time for program implementation in the early Summer of 2003 (WS-3 RT. 279:14–282:9). Early summer 2003 remains our goal because it allows us the optimal period to collect data about the strengths and weaknesses of the approaches adopted in Phase 1. By addressing cost recovery concerns at this juncture, we intend to provide the necessary assurances that will allow respondents to begin working on implementation system details with a view to meeting that early Summer 2003 goal.

Therefore, respondents should assume that the Commission will not adopt demand response tariffs and programs at the conclusion of Phase 1 unless it also determines that doing so is in the public interest. All involved in this collaborative proceeding are attempting in good faith to build the record necessary to support such a public interest finding. The principals are also interested in rapid implementation of the programs ultimately adopted. That means cost recovery for these programs must be addressed in the Phase 1 decision. Therefore it is critical that, if they have not already done so, respondents present their proposals for necessary cost recovery mechanisms during the WG 2 and WG 3 process. For each proposal advanced by the working groups at the conclusion of the working group process, we will expect to see an explicit cost recovery mechanism that has been vetted in the working group setting. [3]

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[3] Other parties, such as the San Francisco Community Power Cooperative, who may be interested in pursuing non-utility programs, should also be prepared to propose

*Footnote continued on next page*

### D. Direct Access Customers

Noting that there is significant uncertainty about our legal authority to require Energy Service Providers to offer dynamic tariffs to their customers, the October 2nd Ruling requested comment on that issue, as well as on two possible approaches for direct access load to participate in demand response tariffs and programs. The first approach involved design of a model dynamic pricing tariff available to IOU retail customers that may or may not be offered as a direct access tariff depending upon the disposition of the legal authority question. The second option involved design of a wholesale market bidding program available to all customers with demands over 200 kW in the state (or at least whose power is delivered through the ISO markets), including direct access. The parties[4] who addressed this issue endorsed the second approach of designing a wholesale market bidding program available to customers with demands over 200 kW. SDG&E noted that if such a program is offered through the ISO, it can act as a supply source for daily balancing. PG&E is concerned that due to jurisdictional issues, the Commission itself not develop such a program, but rather leave this to the ISO.[5] We see no reason that WG 2 could not develop a wholesale level program that would interface with or participate in ISO markets. Thus, we expect the parties to focus on this second approach, and to work with the parties active in the state's wholesale power markets, including CPA's Demand

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specific funding mechanisms or identify potential funding alternatives for those programs in the WG 3 report.

[4] SDG&E's Comments to the October 2nd Ruling, pp. 6-7. See also comments filed by the Alliance for Retail Energy Markets ("AreM") and the Western Power Trading Forum.

[5] PG&E Comments to the October 2nd Ruling, pp. 8-9.

Reserves Partnership (DRP) program (as applicable) and the respondent utilities' current power procurement activities, in doing so.

### E. Interaction with Utility Procurement Function

In a recently issued decision (D.02-10-062)[6] in the procurement rulemaking[7], the CPUC required that utilities include demand response resources as part of their short-term and long-term procurement planning process. The CPUC also required utilities to provide for reserve requirements, and include demand response resources as part of their plans to meet the reserve requirements. The utilities' short-term plans were due on November 12, 2002, with long-term plans due on April 1, 2003. In preparation for the long-term plans, and after consultation with the assigned ALJ in R.01-10-024, we ask the following of the respondents:

- To come to the next WG 1 meeting prepared to describe how demand response resources, including reserve levels, were included in their November 12, 2002 procurement filings.
- To respond to the following questions related to long-term planning, in a set of comments on this ruling to be filed on November 26, 2002. Other parties may also file written comments on the same date.

  1. What process will/should the utilities use to plan for inclusion of demand response resources in their long-term procurement plans?
  2. How will demand response resources be included in the long-term plans?

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[6] See especially pp. 28-30, Sections V. (D) and (E).

[7] R.01-10-024.

3. How will/should the results of this demand response proceeding interface with utility procurement planning?

4. What reserve levels do the utilities plan to include in their plans? How much of those reserves will be met through demand response and why? Or, if the exact answers are not yet known, what process will/should be used to optimize use of demand response resources to meet reserves?

5. What is the transition plan for integration of the CPA DRP program if/when CPUC approval is granted for assignment of the contract to utilities? What issues need to be addressed to ensure a smooth transition?

### F. The Potential for WG 3 "Quick Wins"

Early in this proceeding, we required respondents to submit the details of existing demand response programs and pricing options. Respondents filed these reports on August 9, 2002. The Commission also received related reports from the California Energy Commission (CEC), the California Consumer Power and Conservation Financing Authority (CPA), along with comments from Grid Services, Inc.

While WG 3 has been free to develop a variety of demand response programs and pricing options for residential and small commercial customers, we expect that some proportion of the proposals submitted to us by WG 3 will build upon existing programs and pricing options detailed in respondents' August 9th reports. Such options, based on existing programs, provide the possibility for some "quick wins" by Summer 2003 in the demand response area for those customers addressed in the WG 3 effort. These modifications should require only a small amount of incremental effort to implement.

### G. AMR Consideration in Phase 2

When this rulemaking was initiated, the Commission indicated its interest in infrastructure development and its desire to take evidence on the various benefits and costs that could be associated with universal advanced meter deployment (see, generally, R.02-06-001, mimeo pp. 5 –9). We indicated that we would consider the development of a plan for deployment of advanced metering appropriate to the needs and capabilities of different types of customers, and noted that we would investigate a broad range of options including universal choice and Commission or utility-selected solutions.

As events ultimately unfolded, we opted to defer the consideration of these infrastructure issues until after we had developed additional programs and pricing options in the Phase 1 WG 2 and WG 3 process. We now place the parties on notice that we will look at the issues associated with universal deployment of advanced metering in the next phase of this proceeding. The parties can expect that the Phase 1 decision will note this issue, among others, as it delineates the scope of the next phase of this rulemaking.

## III. Next WG 1 Meeting: December 4, 2002

The final agenda for the December 4, 2002 WG 1 meeting will be available on the CPUC's website at least 48 hours in advance of the meeting. At this point, however, we know that the following topics will be included on that agenda, consistent with the preceding discussion, and provide this information for the assistance of the parties who plan to participate in the December 4$^{th}$ meeting.

1. Coordination with procurement (see Section II.E, above).
2. Cost recovery proposals (see Section II.C, above).
3. Finalizing the vision statement, based on comments filed on November 8, 2002.
4. Brief status reports from the WG 2 and WG 3 facilitators.

We expect the respondents to come to the working group meeting prepared to address Topics 1 and 2 above in detail.

## IV. Scheduling Changes

Additional meetings for WG 2 and WG3 have been scheduled, as reflected on the Commission's Daily Calendar and as shown in a revised document listing the dates and locations for working group meetings[8]. An extension in the schedule of WG 3, whose meetings now conclude on November 26, 2002, requires that the due date for the WG 3 report be extended from November 14, 2002 to December 3, 2002. This ruling so provides.

As noted previously, WG 1 will meet again on December 4, 2002. We also anticipate that WG 1 will meet again in late December or early January, and will advise the parties of this new date as soon as it is known.

**IT IS RULED** that:

1. Cost-effectiveness analysis done in Phase 1 of this proceeding should include at least the following scenarios for valuing demand responses and the specific values outlined previously in this ruling:

Alternative 1: A newly constructed peaker plant; simple cycle technology with a heat rate of 10,000 btu / hour.

Alternative 2: An existing, older peaker plant with a heat rate of 20,000 btu / hour.

2. WG 2 should begin working on a schedule for full analysis, development and implementation of a two-part tariff in the next phase of this proceeding, and include that schedule in its Phase 1 report.

3. For each proposal advanced by the working groups at the conclusion of the working group process, we will expect to see an explicit cost recovery mechanism that has been vetted in the working group setting. As part of this

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[8] The document entitled "Remaining Dates and Locations for Working Group Meetings," revised November 13, 2002, is Item 2 attached to this ruling.

same vetting process, other parties who may be interested in proposing non-utility programs shall also propose specific funding mechanisms or identify potential alternatives for funding such programs

4. In dealing with participation of large customer direct access load, we expect the parties to focus on the second option outlined in the October 2nd ruling, a wholesale market bidding program available to all customers with demand over 200 kW in this state, and in so doing, to work with all relevant parties active in the state's wholesale power market.

5. At the December 4th WG1 meeting, respondents shall be prepared to (i) describe how demand response resources, including reserve levels, were included in the procurement filings made in mid-November as required by D.02-10-062 in R.01-10-024, and (ii) address questions from WG 1 relative to the written comments about long-term planning provided on November 26th in response to Section II.E of this ruling.

6. Some portion of the proposals submitted to WG 1 by WG 3 should build upon the existing programs and pricing options detailed in respondents' August 9th reports in R.02-06-001.

7. We hereby place parties on notice that WG 1 will look formally at the issues associated with universal deployment of advanced metering during Phase 2 of this proceeding.

8. The scheduling changes, and specifically the new due date for the WG 3 report, detailed in Section IV of this Ruling, are hereby adopted.

Dated November 13, 2002, at San Francisco, California.

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| /s/ MICHAEL R. PEEVEY<br>(by Julie Fitch)<br>Michael R. Peevey | /s/ LYNN T. CAREW<br>Lynn T. Carew |

Assigned Commissioner | Administrative Law Judge

**Item 1**

# Summary of Cost Recovery Issues

**For discussion at Working Group 1 meeting in R.02-06-001**
**October 15, 2002**

### *Infrastructure Investment*

Capital additions?

- Metering infrastructure
- Communications technology
- Billing system modifications/upgrades
- Data storage and retrieval systems

### *Programmatic Expenses*

- Tariff/program design costs
- Administrative costs
- Consumer education
- Program or tariff/marketing and outreach
- Data collection/research/evaluation

### *Revenue Neutrality*

- By customer
- By customer class
- Overall

### *Los Revenues*

What if we succeed and demand is significantly reduced overall?

- Electric revenue adjustment mechanism (ERAM)?
- Other options?
- Need to cover unavoidable fixed costs (e.g., DWR bonds)

# Item 2

## R.02-06-001 (Demand Response Rulemaking)
## Remaining Dates and Locations for Working Group Meetings

| | | |
|---|---|---|
| WG 3 | November 18, 2002<br>10:00 am to 4:00 pm | CPUC Auditorium<br>San Francisco |
| WG 2 | November 19, 2002<br>10:00 am to 4:00 pm | CPUC Hearing Room A<br>San Francisco |
| WG 3 | November 26, 2002<br>10:00 am to 4:00 pm | CEC Building (Hearing Room A)<br>1516 Ninth Street<br>Sacramento |
| WG 2 | December 3, 2002<br>10:00 am to 4:00 pm | CPUC Hearing Room A<br>San Francisco |
| WG 1 | December 4, 2002<br>2:00 pm to 5:00 pm | CPUC Auditorium<br>San Francisco |
| WG 2 | December 10, 2002<br>10:00 am to 4:00 pm | CPUC Hearing Room A<br>San Francisco |

## CERTIFICATE OF SERVICE

I certify that I have by U.S. mail, and by electronic mail to the parties to which an electronic mail address has been provided, this day served a true copy of the original attached Assigned Commissioner's and Administrative Law Judge's Ruling Following The Third Meeting Of Working Group 1 on all parties of record in this proceeding or their attorneys of record.

Dated November 13, 2002, at San Francisco, California.

/s/ JANET V. ALVIAR
Janet V. Alviar

## N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to ensure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.